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BEFORE THE

IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE INVESTMENT IN SELECTIVE CATALYTIC REDUCTION CONTROLS ON JIM BRIDGER UNITS 3 AND 4.	CASE NO. IPC-E-13-16

NON-PROPRIETARY DIRECT TESTIMONY AND EXHIBITS OF MIKE LOUIS

IDAHO PUBLIC UTILITIES COMMISSION

OCTOBER 11, 2013

Q. Please state your name and business address for the record.

A. My name is Mike Louis. My business address is 472 West Washington Street, Boise, Idaho.

Q. By whom are you employed and in what capacity?

A. I am employed by the Idaho Public Utilities Commission as a Utilities Analyst.

Q. What is your educational and professional background?

A. I received my Bachelor and Master of Science degrees in Industrial Engineering with concentrations in manufacturing systems and engineering economics from Purdue University in 1985 and 1992, respectively. I also received my Masters in Public Policy and Administration at Boise State University in 2005. In addition to my formal education, I have attended Michigan State University Institute of Public Utilities Annual Regulatory Studies Program, NARUC Utility Rate School, Electricity Grid School, and Advanced Regulatory Studies Program.

My work experience includes 18 years of industrial/commercial practice developing and managing manufacturing systems and operations, planning processes, and supply chains for General Motors, Hewlett-Packard, Jabil Circuit, and Albertsons Companies. I also have spent six years administrating and conducting energy policy research with the Energy Policy Institute at Boise State University. As part of my manufacturing and academia experience is the management of departmental budgets as a mid-level manager and project budgets as a manager of several large strategically-oriented projects. I have also taught classes in program and project management in the Department of Public Policy and Administration at Boise State University.

At the Idaho Public Utilities Commission, my work responsibilities have included a variety of electric and natural gas cases including integrated resource plans, purchased gas and power cost adjustment cases, prudence reviews of power plant investments, and several general rate cases looking specifically at emission control investments.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe Staff's analysis as to the prudence of the Company's proposed investment in selective catalytic reduction (SCR) controls on Jim Bridger Units 3 and 4. In addition, I provide recommendations related to the issuance of a Certificate of Public Convenience and Necessity (CPCN) and propose ratemaking treatment.

Q. Please summarize your testimony in this case.

A. I believe the Company's decision to move forward with the emission control investment project for Jim Bridger Units 3 and 4 is prudent; supporting authorization of a CPCN issued under *Idaho Code* §61-526. However, I only recommend authorization of $81,378,000 in direct project costs of the $117,947,962 requested in the Company's Application based on provisions for binding ratemaking treatment under *Idaho Code* §61-541. I have also made several recommendations related to the handling of variances between the Commitment Estimate and actual costs.

Q. What documents did you analyze that lead to your recommendation?

A. I examined the following documents:

1. The Company's Application, direct testimony of Company witnesses, and accompanying exhibits;
2. Idaho Power's 2013 Integrated Resource Plan;
3. Discovery by Staff and intervening parties including but not limited to the Company's most recent business plan, Engineering, Procurement, and Construction (EPC) contractor evaluation documents, EPC Contract, and the Jim Bridger operations contract between Idaho Power Company and PacifiCorp;
4. PacifiCorp's CPCN cases in Wyoming and Utah

including the Application, testimony, discovery requests, and orders;

5. Idaho's CPCN statutes including *Idaho Code* §61-541, and §§61-526 through 61-530;

6. Environmental Protection Agency's (EPA) proposed rule on the Wyoming SIP contained in the Federal Register (Vol. 78, No. 111, June 10).

Q. How will your testimony be organized?

A. My testimony can be broken down to an analysis of two objectives related to concepts of prudency: 1) whether or not it is prudent to recommend issuance of a CPCN pursuant to *Idaho Code* §61-526 and 2) whether and to what extent the Company's proposed budget should be pre-approved for binding ratemaking treatment pursuant to *Idaho Code* §61-541.

I begin by considering questions related to whether or not a CPCN should be issued. I consider if the Company's decision to invest in emission controls is necessary and whether the project is least cost and least risk for customers over the long-term when compared to other alternatives given information known at this time.

The second objective considers factors that ensure the project is constructed and deployed in a cost effective manner. First, under *Idaho Code* §61-541

(2)(b)(iii), I analyze whether any or all of the Company's proposed budget for the SCR investments should be pre-approved by the Commission. Second, under *Idaho Code* §61-541 (2)(b)(iv), I recommend an approach for handling project variances. A table of contents is provided below.

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Prudence of Proposed Investment

Drivers for Investment

Q. Please describe the primary drivers for the need to invest in SCR emission controls for Jim Bridger generating Units 3 and 4.

A. In compliance with Clean Air Act Regional Haze (RH) rules, The Wyoming Department of Environmental Quality (WDEQ) through its State Implementation Plan (SIP) requires the Company to install SCR emission controls by December 2015 on Jim Bridger Unit 3 and by December 2016 on Unit 4 to limit Nitrogen Oxide (NOX) emissions to 0.07 lbs/MMBtu (on a 30-day rolling average). Because the SIP is enforceable by the State of Wyoming, the Company must discontinue operation or install the necessary controls by the dates stipulated in the SIP to continue operation.

The Company relies on 174 MW and 177 MW of net dependable baseload capacity from Units 3 and 4, respectively. This represents approximately 10% of Idaho Power's total system generation capacity and approximately 19% of the Company's baseload capacity. The Company would need to maintain at least an equivalent amount of baseload capacity to continue to reliably and economically meet customer's electricity needs. Therefore, permanently halting operation of Bridger Units 3 and 4 without replacing its generation capacity is not an option.

Sufficiency of Company Analysis

Q. Please provide a brief description of the Company's analysis.

A. The Company's analysis consisted of two separate types of studies: (1) a static unit by unit analysis performed by an outside consultant, and (2) a system analysis using fixed cost assumptions from the static analysis combined with variable costs derived from the Company's AURORA model.

For both studies, net present value (NPV) cost comparisons were made using alternatives to investing in SCR controls. Nine different combinations of natural gas and carbon price forecasts were examined. The NPV costs were calculated across a twenty-year time period from the year 2013 through 2032.

The static analysis looked at each Jim Bridger unit individually. This analysis provides a cost comparison for each alternative resource as if it is dispatched in exactly the same way as the Jim Bridger unit it is assumed to replace. Although this analysis illustrates the operating characteristic differences between the different alternatives, its value is limited because the calculated NPV costs are not representative of how the alternative would be realistically dispatched within the Company's overall system.

By contrast, the system analysis dispatches each generation resource based on its own costs and operating characteristics. For example, gas generation alternatives are dispatched according to their respective fuel costs and heat rates, instead of being dispatched like the coal units they are intended to replace. Because of these reasons, the Company's system analysis more realistically reflects how each alternative might actually operate in the Company's system. This provides more realistic NPV comparisons when testing sensitivity to natural gas and carbon prices.

Q. What alternatives to the "Upgrade" proposal, investing in SCR controls for Jim Bridger Units 3 and 4 on the SIP compliance deadlines, did the Company choose to compare?

A. Idaho Power analyzed and compared the following four different alternatives to the "Upgrade" proposal:

1. Natural Gas Conversion - Each Jim Bridger unit is converted to natural gas fuel by the SIP compliance deadlines.

2. Retire and Replace - Each Jim Bridger unit is retired and replaced by an equal-sized combined cycle combustion turbine (CCCT) gas plant with operating characteristics similar to the Langley Gulch CCCT plant by the SIP compliance deadlines.

3. CTA Natural Gas Conversion - This is a compliance timing alternative (CTA) that is identical to the "natural gas conversion" alternative described in number 1 above, except it is assumed the SIP compliance deadline can be delayed by five years.

4. CTA Retire and Replace - This is a compliance timing alternative (CTA) that is identical to the "retire and replace" alternative described in No. 2 above, except it is assumed the SIP compliance deadline can be

delayed by five years.

Q. Were the number and type of resource alternatives reasonable for comparison purposes?

A. I believe so. Based on Idaho Power's analysis methodology, I believe the goal was more to confirm the installation of emission controls as the most economical solution given current and future circumstances rather than to identify the one best solution using a clean sheet approach. By using an incremental approach, the Company was able to use a minimal set of highly feasible alternatives to get an indication it was choosing the best course of action. The strength of that indication, which in this case is the magnitude of difference in NPV between each alternative and the "Upgrade" proposal, told the Company if it was making the best decision or if a more detailed and rigorous analysis was warranted.

Q. How did you assess if the alternatives used were feasible and suitable for comparison?

A. I identified four factors that are important to test feasibility. To be feasible, the alternative needed to meet all four criteria. First, all the alternatives needed to meet the reliability needs of Idaho customers. As explained previously, Jim Bridger Units 3 and 4 provide approximately 19% of the Company's baseload generation capacity. In addition, Idaho Power already has a large amount of seasonal or intermittent hydropower and wind resources. Alternative resources considered as part of the analysis must be dispatchable and reliable year round.

Second, the alternatives needed to have a cost that can reasonably compete with an SCR equipped Bridger unit to minimize rate impact to Idaho customers. The Jim Bridger facility currently has the lowest dispatch cost of all of the Company's generation resources. The types of alternatives that can compete economically while meeting all the other criteria is realistically very limited, even with the additional cost of SCR controls and potential future environmental compliance costs.

Third, the alternatives needed to meet or surpass all current and potential environmental regulations relevant to each alternative, including regulations under consideration for the Jim Bridger units.

Finally, all alternatives for comparison needed to be constructed and operational by the SIP compliance deadline.

Q. Do you believe the compliance timing alternatives considered by Idaho Power were realistic?

A. At one time there may have been an opportunity to negotiate a delay in the Regional Haze compliance dates in exchange for shutting down one or both units and replacing them with an alternative resource. However, I believe the opportunity for delay no longer exists.

Q. Why do you believe the opportunity to delay compliance no longer exists?

A. There are several reasons. First, the Wyoming SIP carries the force of law in the State of Wyoming until such time as the EPA approves it or replaces it with a Federal Implementation Plan. Second, on May 23, 2013, the EPA created additional certainty by re-proposing rules that will approve the Wyoming SIP making the SIP requirements federally enforceable upon final approval. Third, PacifiCorp, as a majority partner and owner-operator of the Jim Bridger facility, is moving forward with installing the controls. It received a CPCN in both Utah and Wyoming on May 29, 2013 and May 10, 2013, respectively, and signed an Engineering, Procurement, and Construction (EPC) contract to install the controls. In reviewing the contractual obligations between the two companies, I believe it would be very difficult for Idaho Power to pursue a different alternative than what PacifiCorp has already selected without significant additional cost.

Q. What would Idaho Power need to do if it decided not to participate in PacifiCorp's installation of environmental controls?

A. I believe the most feasible option would be for Idaho Power to sell its share of the facility to PacifiCorp or a third party. Although the possibility exists, I believe there is little incentive for PacifiCorp or a third party to buy out Idaho Power's share in the time frame required. Moreover, Idaho Power would incur potential costs associated with stranded assets, the additional cost of replacing lost Jim Bridger capacity, and damages owed to PacifiCorp for breach of contract (See Company response to Staff Production Request No. 9 attached as Staff Exhibit No. 101).

Q. Despite your belief that negotiating a delay in the compliance deadlines in exchange for shutting down Units 3 and 4 is not realistic, do you see value in analyzing the compliance timing alternatives?

A. Yes I do. I believe the CTA analysis demonstrates how much more cost effective Idaho Power's proposal is over the "natural gas conversion" or "retire and replace" alternatives. With the CTA option, the "natural gas conversion" and "retire and replace" alternatives allow operation of Jim Bridger Units 3 and 4 without additional operational and capital costs of SCR controls for a period of five years. It also avoids five years of carrying costs associated with the capital required to build a CCCT plant or to convert Jim Bridger Units 3 and 4 to burn natural gas. Even with these advantages, the SCR "Upgrade" option was most economical, providing further evidence justifying the Company's proposal.

Q. Please describe how Idaho Power evaluated risk associated with each of the alternatives considered.

A. The Company's analysis focused on two primary risk factors that would cause significant NPV differences between each of the alternatives: carbon dioxide (CO2) price and natural gas price. These factors were chosen because the alternatives being compared are primarily fueled by coal or natural gas. The Company calculated nine NPV results using combinations of three different CO2 and three different natural gas price forecasts. Comparing the NPV results across the nine alternative model runs provides an effective evaluation of risk associated with each resource alternative.

Overall, I believe the factors chosen and the methodology used to evaluate risk in the Company's analysis are reasonable.

Q. Do you believe the natural gas and CO2 price forecasts used are reasonable?

A. I do, with some caveats related to the natural gas price forecast. First, the natural gas and CO2 price forecasts were identical to the forecasts used to develop the 2013 Integrated Resource Plan (IRP). This means they were reviewed publically through the IRP Advisory Council as part of the IRP development process.

Second, the forecasts were based on data from reputable third party sources. The CO2 price forecast utilized data from the "2011" and "2012 Carbon Dioxide Price Forecast" published by Synapse Energy Economics, Inc. The natural gas forecast was derived from the "Annual Energy Outlook, 2012" published by the US Energy Information Administration (EIA).

With respect to CO2, the Idaho Power CO2 price forecast is somewhat more conservative when compared to the forecast used by PacifiCorp in its 2013 IRP. This favors the "natural gas conversion" and "retire and replace" alternatives by phasing in CO2 cost earlier. It also provides a forecast that is approximately equal to the PacifiCorp forecast in the low and planning CO2 cases and consistently higher in the high CO2 case over the analysis time period.

However, I believe the Company's natural gas forecast may be less conservative by being higher than other nominal forecasts. This favors investment in SCR controls over natural gas fueled alternatives. The Company applied a three percent inflation rate to the EIA forecast in real 2010 dollars to get a nominal dollar forecast over the planning period. When compared to PacifiCorp or EIA's nominal dollar forecast, Idaho Power's gas price forecast is considerably higher, especially in the out years. Although I don't believe the Company's method is necessarily unreasonable, I believe that using EIA's nominal dollar forecast is more transparent and uses an inflation rate that is likely more accurate for natural gas. For comparison purposes, these forecasts are illustrated in Staff Exhibit No. 102.

Q. How does Idaho Power's comparatively higher natural gas price forecast affect the analysis?

A. To better understand how the natural gas forecast affected the analysis, I looked at the "tipping point" analysis provided by the Company in response to Staff Production Request No. 44. The analysis determined how much gas prices would need to decrease to make the next best alternative more economical than investing in SCR controls (the planning CO2 price forecast was used as the baseline). The analysis showed that natural gas prices on average would need to decrease by 52 percent in order to make the "retire and replace" with a CCCT alternative more economically favorable. Because this percentage decrease is larger than the percentage difference between the Company's gas price forecast and EIA's nominal forecast, I concluded that the differences in the natural gas price forecasts are not substantial enough to change the Company's final recommendation. Regardless of the forecast used, the forecast would have to be considerably lower.

Q. Were there any other important factors to consider regarding risk?

A. The other important factor is the cost of compliance for future environmental regulations beyond Regional Haze. For some of the regulations, there is considerable uncertainty about what will be required. Potential future regulations subject to consideration for Jim Bridger Units 3 and 4 include: (1) Mercury and Air Toxic Standards (MATS) Rule, (2) Clean Water Act Section 316(b), (3) Coal Combustion Residuals (CCR), and (4) future regulations to limit greenhouse gas emissions.

Q. How did Idaho Power account for these potential compliance costs?

A. With the exception of greenhouse gas regulations, the Company included incremental capital and operation and maintenance costs for controls required by each regulation depending on the type and technology of each alternative under consideration. Most of the incremental cost estimates were originally developed by PacifiCorp. However, the consultant hired by Idaho Power to do the "static" analysis was tasked to review and validate all of the capital and variable cost assumptions, including the cost of replacement capacity and environmental compliance costs for each alternative. Given the highly technical nature of environmental control technology, I believe this approach provided reasonable assessment of potential future environmental costs and added credibility to the Company's analysis.

Q. How did Idaho Power account for greenhouse gas regulation compliance costs?

A. EPA Greenhouse gas regulations for existing sources are currently not expected to be finalized until June of 2015. Nevertheless, the Company included a surrogate CO2 cost adder to the variable cost of each alternative on a dollar per megawatt-hour basis with the full CO2 cost charged to coal-fueled alternatives and 50% of the cost charged to natural gas fueled alternatives because CO2 emissions for natural gas are approximately half that of coal. As mentioned earlier, the CO2 cost was included as a sensitivity variable. I believe this is reasonable treatment for greenhouse gas compliance costs until a framework for EPA rulemaking is proposed and finalized.

Q. Did higher CO2 prices affect the NPV results?

A. When high CO2 costs were combined with the low natural gas price forecast in the Company's analysis, the "retire and replace" was a better alternative economically than the "upgrade" proposal based on the NPV results. To understand the sensitivity of the analysis on CO2 price alone, I requested the Company perform a "tipping point" analysis to determine how much CO2 prices would need to increase to make the next best alternative more economical than investing in SCR controls using the planning natural gas price forecast case as a baseline. The analysis showed that CO2 prices on average would need to increase approximately 423 percent in order to make the "retire and replace" alternative more economically favorable.

Q. Is there anything else you considered in the Company's analysis leading to its decision to upgrade Jim Bridger Units 3 and 4?

A. Yes. The EPA has not yet approved the Wyoming SIP regarding NOX compliance for Bridger Units 3 and 4. However, after several delays by the EPA, the agency released a re-proposal to effectively approve SCR installation on Units 3 and 4 by December 2015 and 2016, respectively, by authorizing an emission limit of 0.07 lbs/MMBtu. If the EPA issues a notice of final rulemaking on November 21, 2013 as expected with no changes to the re-proposal, it will effectively make installation of SCR controls federally enforceable. In the unlikely event that the EPA decides to change the Wyoming SIP, it would probably make the requirements more stringent.

Q. Did the Company consider this contingency?

A. Yes. The Company, through PacifiCorp as the operator of the plant, has signed a Limited Notice to Proceed (LNTP) contract with an EPC contractor to design and install the controls. The LNTP allows the Company flexibility to make changes to the specifications of the design and purchased equipment to meet a 0.05 lbs/MMBtu NOX limit up to the date the EPA is expected to issue its final rules.

Q. Would the additional cost of meeting a more stringent emission limit change the outcome of the alternative analysis performed by the Company?

A. I do not believe it would. Based on the Company's response to Staff Production Request No. 6, the incremental capital cost of meeting a 0.05 lb/MMBtu NOX limit is estimated to be less than $1.7 million per unit. Amortized over the life of the unit and brought back to present value over the study period, the effect on the NPV results for the "upgrade" proposal would not make a material difference.

Q. What do you recommend based on your review of the Company's analysis?

A. Based on the overall sufficiency and reasonableness of the Company's analysis and also based on the overall magnitude of difference in net present value between each alternative and the "upgrade" proposal for the different sensitivity scenarios, I agree with the Company's "upgrade" proposal and recommend the Commission issue a CPCN pursuant to *Idaho Code* §61-526.

Prudence of the Project Budget

Maximum Pre-approved Amount

Q. How did you determine your recommended level of project costs eligible for binding ratemaking treatment pursuant to *Idaho Code* §61-541?

A. Pursuant to *Idaho Code* §61-541 (2)(b)(iii), the Commission is to consider "the maximum amount of costs that the Commission will include in rates at the time determined by the Commission without the public utility having the burden of moving forward with additional evidence of the prudence and reasonableness of such costs." Based on this guidance, I believe binding ratemaking treatment in this case should be limited to only those expense categories that are necessary, and known and measurable with a high level of certainty. I also recommend that each category of costs should be pre-approved individually rather than on a total project cost perspective. This protects against premature approval of budgeted amounts when actual costs on an individual category basis could be potentially lower. This approach ensures the Commission's right to review the prudency of actual cost before they are put into rates.

Q. Why should uncertain budgeted amounts for individual project categories be excluded from pre-approval?

A. There are two reasons. First, excluding uncertain amounts incents the Company to continue to find cost-effective ways of implementing a project once it is underway. Pre-approval of budgeted amounts that are set using liberal estimating methods or that include slack from contingency amounts allow project managers to spend up to the amount of their authorized budget without regard for potential savings. Second, excluding uncertain amounts protects against recovery of a full pre-approved amount if actual costs are less. Consequently, I recommend that the Commission conservatively set pre-approved project costs to assure costs are reasonably incurred in all cost item categories throughout project development.

Q. Will the Company have difficulty financing the project if the Commission denies pre-approval of costs on a total project basis?

A. Not necessarily in this case. In response to Staff's Production Request No. 18, which asks how the project will be financed, the Company said,

> Idaho Power expects to finance this project consistent with the financing of its total construction program. The Company expects to finance its capital requirements with a combination of internally generated funds and externally financed capital. Idaho Power has not entered into any alternative financing agreements and therefore has not developed a financing payment schedule based on non-traditional financing schemes.

Because Idaho Power is using a combination of internally generated funds and capital from its overall construction program budget and is not required to secure financing specifically for this project, the need for binding ratemaking treatment to secure favorable financing is reduced. Moreover, the Company's ability to secure favorable financing is not a requirement of *Idaho Code* §61-541.

Therefore, more of the focus should be placed on assuring that project costs are properly incurred and are subject to review when actual costs are known. This means that uncertain budgeted amounts should not be included in the pre-approved total.

Q. Does Idaho Power's shared ownership of Bridger with PacifiCorp affect your recommendations in this case?

A. Yes. PacifiCorp, as the operator of the plant, has the responsibility to manage the project. However, Idaho Power still has a responsibility to make sure PacifiCorp does everything it reasonably can to implement the project cost-effectively.

Q. Is there evidence that the Company has had difficulty providing managerial oversight of its operating partner's operating and investment decisions in the past?

A. Yes. For example, in Oregon Case UE 233 (Order No. 13-132), the Oregon Commission disallowed Idaho Power management expenses because the Company was "unaware of the existence of a key study underlying the decision to upgrade Bridger 3," in its general rate case.

Q. What amount do you recommend for pre-approval in this case?

A. The only costs I recommend for binding ratemaking treatment are the amount of the EPC contract and actual costs already incurred during the development phase. I have illustrated my recommendations for budget pre-approval by expense category in Staff Exhibit No. 103.

Q. Please explain how Staff Exhibit No. 103 is organized relative to your testimony.

A. Staff Exhibit No. 103 illustrates amounts included and excluded in Staff's proposed Commitment Estimate by cost item category. Amounts included in Staff's proposed Commitment Estimate are further broken down by actual cost shown in Column 1 and by estimates from competitive bids and contracts shown in Column 2 with Staff's total proposed amounts shown in Column 3. Amounts excluded from Staff's proposal are shown in Columns 4 and 5. Column 4 shows amounts that require both full prudence review and cost verification because there are questions whether the cost item is necessary. Column 5 reflects amounts for cost item categories that I believe are necessary; however, the amounts are uncertain at this time requiring future cost verification. Column 5 reflects Idaho Power's proposed Commitment Estimate contained in the Company's Application.

Q. Why did you recommend pre-approval of only [redacted] in actual costs from the development phase category?

A. I was able to review [redacted] in actual cost included in the development phase and determine it was reasonable and prudent. The certainty of remaining forecasted costs were harder to ascertain. Thus, my recommendation to leave them out of the Commitment Estimate for future approval.

Q. Why do you recommend that the full [redacted] cost for the EPC contract be included in Staff's Proposed Commitment Estimate?

A. The EPC contractor was selected through a reasonable and prudent competitive bidding process. The process provided certainty that the contract would be awarded to the lowest cost contractor best able to meet PacifiCorp's needs. Because a contract was signed, a framework to ensure performance and cost guarantees was developed that provides certainty around the Company's estimate, thereby making it known and measurable.

Q. Please generally describe PacifiCorp's competitive bidding process.

A. Twenty-seven request-for-proposals (RFP) were distributed. Of the RFP's sent out, only five bids were returned or were complete. Using criteria developed prior to the start of the evaluation process, the bids were evaluated using a cross-functional team including a member from an outside engineering firm. Negotiations were conducted with the two finalists with the final selection going to the lowest cost bidder.

Q. Has the Company through its managing partner, PacifiCorp, signed a limited notice to proceed contract to install SCR controls on Jim Bridger Units 3 and 4?

A. Yes. PacifiCorp and, by default due to their joint-ownership, Idaho Power have signed a limited notice to proceed (LNTP) contract with the EPC Contractor to design and install SCR controls. This allows the EPC contractor to begin work on the project while delaying the Company's exposure to significant costs up until the Full Notice to Proceed deadline on December 1, 2013.

Q. Is there an incremental cost associated with this type of contract?

A. Yes. There is a premium of approximately [redacted] for the LNTP contract above the cost of the base contract according to documents supplied by Idaho Power in response to Staff Production Request Nos. 1 and 40.

Q. Is this prudent?

A. I believe it is. As described in the first section of my testimony, uncertainty still exists surrounding EPA's final approval of the Wyoming SIP which the EPA indicated would occur on November 21, 2013. According to Staff Production Request No. 2 and PacifiCorp testimony in the Utah CPCN case, delaying the contract past May 31, 2013 would put Regional Haze compliance by the Wyoming SIP deadlines at risk. Although the EPA did recommend approval of the Wyoming SIP in its re-proposal submitted on May 23, 2013, because of the number of EPA delays that have already occurred, uncertainty remains whether the requirements will change. Signing a LNTP contract provides a way to alleviate risk of non-compliance due to time constraints while providing flexibility to change the design to meet more stringent emission requirements if the EPA changes them in its final rules.

In response to Staff Production Request No. 57, the Company justified the cost premium based on increased equipment and material cost due to delayed purchase orders and higher labor rates from a compressed construction schedule. I believe the costs are justified.

Q. Please explain why you specifically excluded the Company's estimate for the Boiler and Pre-heater Economizer Upgrade in Staff's proposed Commitment Estimate.

A. I excluded the full [redacted] cost from the

Commitment Estimate because it is not known and measurable at this point in time. The basis for the estimate is partly derived from a non-competitive proposal from a potential service provider. Without a competitive bidding process or something equivalent, it is difficult to ascertain whether or not the price is reasonable. In addition, information in the proposal reflects uncertainty as to the extent of work that needs to be performed. For example, there is an Electrostatic Precipitator option for Unit 4, which would cost an additional [redacted] that PacifiCorp is not certain is required. The proposal also indicates there is uncertainty due to [redacted] which has prevented the service provider from providing a full and firm price for installation. PacifiCorp estimated this additional cost by basing it on comparable cost for a similar installation on PacifiCorp's Naughton Unit 1. Given the potential cost difference in estimates for Bridger Unit 3 [redacted] and Unit 4 [redacted] for the same type of work within the same proposal, I believe estimates for additional work at a totally different facility to be at least equally uncertain.

Q. Why did you exclude the Company's estimate for the Low Temperature Economizer in Staff's proposed

Commitment Estimate?

A. I excluded the full [redacted] from the Commitment Estimate because there is a question whether any investment is necessary at all, requiring a full prudency review when there is more certainty. The basis for the estimate is a non-competitive proposal from a potential service provider. In the proposal, the service provider recommends five separate options that range in cost from [redacted] only requiring a change in operating procedures to installing an economizer that could cost up to [redacted]. Because of the potential to operate the generating units without any investment, in my opinion, a full prudence review is required.

Q. Why did you exclude the Company's estimate for the [redacted] cost for the economizer upgrade, the [redacted] cost for flue gas reinforcement, the [redacted] cost for spare parts allowance, and [redacted] in other cost expense in Staff's Proposed Commitment Estimate?

A. Again, none of these costs are known and measurable at this time. All of these costs were estimated using comparable costs for similar work and expenses at Naughton Unit 3, and Naughton Units 1 and 2. For reasons stated earlier regarding a lack of a competitive bidding process or equivalent, and the level of difference and uniqueness between generation units contributing to a high level of uncertainty, I believe the amounts should be reviewed as actual costs when they are known and when the Company files to have them recovered in rates.

Q. Please provide a summary of your recommendations for a pre-approved budget amount.

A. The amounts below summarize the Commitment Estimate I am recommending the Commission adopt in this case.

Staff Commitment Estimate ($000's)

	Unit 3	Unit 4	Total
Development Phase	[redacted]		
EPC Contract	[redacted]		
Total Direct	$39,648	$41,729	$81,378

Method of Handling Project Variances

Q. What are the Commission's responsibilities regarding project variances?

A. *Idaho Code* §61-541(b)(iv) states that ratemaking treatments are to include "the method of handling any variances between cost estimates and actual costs."

Q. How do you recommend that variances between cost estimates and actual cost be handled?

A. I have five recommendations. First, there should be a mandatory prudence review of actual costs in a subsequent proceeding before the expenses can be put into rates.

Second, in those proceedings, all actual expenditures should be reviewed against pre-approved amounts by cost item category. Any actual cost item category that exceeds the pre-approved budget amount should be reviewed to ensure any amount above the soft-cap for each category is reasonable and prudent. Soft-cap is defined as the maximum amount the Commission will allow without performing a prudence review of any excess amount above the cap before being put into rates. This recommendation is an augmentation of the soft-cap used in the Langley Gulch CPCN case (IPC-E-09-03), where the soft-cap was set for the total approved Commitment Estimate. Unlike Langley Gulch, however, in which the project was constructed mostly under a single EPC contract, this project will possibly entail as many as four additional contracts. Setting a soft-cap for each cost category will ensure a higher level of cost control by not allowing slack in one expense category estimate to serve as a cost contingency for another category with unrelated expenses.

Third, I recommend that the Commission allow either all or none of the expense in any category to be approved. If the Commission only pre-approves a percentage of each category, it is likely the Company will exceed the soft-cap for those categories requiring a full prudence review of all expenses within that category at the time they are put into rates.

Fourth, if the Commission does allow partial pre-approval of the Company's estimate of a cost item category, any amount put into rate base should not exceed the actual cost of that category. The Company says in its Application that, "Should the cost of the project be less than the cost estimate, the savings would directly benefit the customer through a lower amount in rate base." I agree with the Company's proposal that any amount put into rate base should not exceed actual cost. However, I recommend, consistent with my earlier recommendation, that this apply to each cost item category in isolation and not for the total pre-approved amount.

Fifth, the Company should provide to the Commission quarterly project updates that illustrate plan vs. actual status of expenditures by cost item category and for the overall project timeline. This will alert the Commission of major difficulties, unseen circumstances or changes in scope throughout the life of the project. It will also provide better documentation when reviewing prudence in a subsequent proceeding. Finally it will ensure that Idaho Power is actively performing oversight of a project PacifiCorp is managing.

Q. Please discuss any other issues related to variances between cost estimates and actual costs.

A. There was difficulty in reviewing actual development phase expenses. This is due to the way PacifiCorp invoices Idaho Power for its share of the expenses. The line items on the invoice show a breakdown based on the amount of labor, material, travel, etc., which can cut across multiple contracts, work breakdown structure elements, and commitment cost item categories, effectively removing the ability to trace the activity causing the cost. I recommend that the Company develop a method with its partner, PacifiCorp, to ensure the ability to track expenditures by commitment cost category and work breakdown structure element to enable review in future proceedings.

Summary and Recommendations

Q. Please summarize Staff's position and recommendations regarding Idaho Power's CPCN Application.

A. I believe the Company's decision to move forward with the emission control investment project for Jim Bridger Units 3 and 4 is prudent, supporting authorization of a CPCN under *Idaho Code* §61-526.

Regarding binding ratemaking treatment under *Idaho Code* §61-541, I recommend that the Commission pre-approve by cost item category in the amounts of [redacted] for Unit 3 and [redacted] for Unit 4 in development phase cost, and [redacted] for Unit 3 and [redacted] for Unit 4 for the EPC contract for a total of $81.378 million. I also recommend the following regarding methods of handling variances between cost estimates and actual costs:

1. There should be a mandatory prudence review of actual costs in a subsequent proceeding before the expenses can be put into rates.
2. In that proceeding, all actual expenditures should be reviewed against pre-approved amounts by cost item category. Any actual cost item category that exceeds the pre-approved budget amount should be reviewed to ensure any amount above the soft-cap for each category is reasonable and prudent.
3. The Commission should allow either all or none of the expense in a cost item category subject to later approval.
4. If the Commission does allow partial approval of the Company's estimate of a cost item category, any amount put into rate base should not exceed actual cost of that category.
5. The Company should provide to the Commission quarterly project updates that illustrate plan vs. actual status of expenditures by cost item category and for the overall project timeline.

6. The Company should develop a method with its partner, PacifiCorp, to ensure the ability to track costs by cost item category and Work Breakdown Structure element so that prudency can be reviewed on an on-going basis.

Q. Does this conclude your direct testimony in this proceeding?

A. Yes, it does.

CASE NO. IPC-E-13-16

EXHIBIT NO. 101 OF MIKE LOUIS

IS PROPRIETARY

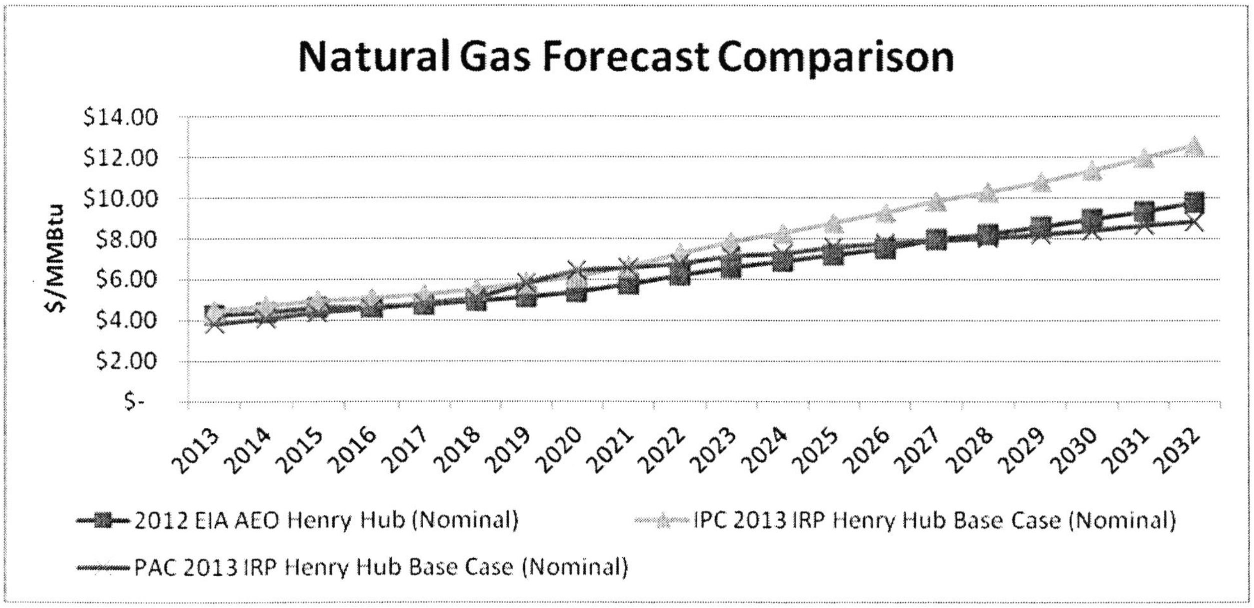

Exhibit No. 102
Case No. IPC-E-13-16
Mike Louis, Staff
10/10/13

CASE NO. IPC-E-13-16

EXHIBIT NO. 103 OF MIKE LOUIS

IS PROPRIETARY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY THAT I HAVE THIS 11TH DAY OF OCTOBER 2013, SERVED THE FOREGOING **NON-PROPRIETARY DIRECT TESTIMONY OF MIKE LOUIS,** IN CASE NO. IPC-E-13-16, BY E-MAILING AND MAILING A COPY THEREOF, POSTAGE PREPAID, TO THE FOLLOWING:

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SECRETARY